Respondent's Exhibit I

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4/18/05
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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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| Illinois Commerce Commission On Its Own Motion, | ) | |
| v. | ) | |
| The Peoples Gas Light and Coke Company | ) | 01-0707 |
| Reconciliation of revenues collected under gas adjustment charges with actual costs prudently incurred. | ) | |

OFFICIAL FILE
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Peoples Exhibit No. I
Witness Puracchio
Date 4/18/05 Reporter TR

REBUTTAL TESTIMONY
OF
THOMAS L. PURACCHIO

Q. Please state your name and business address.

A. Thomas L. Puracchio. 230 County Road 2800 N, Fisher, Illinois 61843.

Q. By whom are you employed?

A. The Peoples Gas Light and Coke Company.

Q. What position do you hold with The Peoples Gas Light and Coke Company?

A. Gas Storage Manager.

Q. What are your responsibilities in that position?

A. I am responsible for the operation of Respondent's Manlove Storage facility which includes the underground storage reservoir and the LNG Plant.

Q. Please summarize your educational background and experience.

A. I received a BSIE from Bradley University in 1984. I have been employed by Respondent since 1984. I was transferred to my current position in December, 2001. Previous positions that I held with Respondent include Gas Control Manager, Customer Service Manager (North Shore Gas Company), and engineer in various operational areas.

Q. What is the purpose of your testimony?

A. My testimony will describe the physical characteristics and operations of Manlove Field, the storage field owned and operated by The Peoples Gas Light and Coke Company ("Respondent" or the "Company"). The purpose is to respond to allegations made by Staff witness Dennis Anderson in his direct testimony that relate to the Company's operation of Manlove Field. I will show that rather than placing Manlove Field at a greater operational risk as this witness suggests, the use of Manlove Field to store volumes above and beyond what the Company specifically requires for its own use has produced real benefits to the Company and its ratepayers. I will also show that certain conclusions that Staff draws from various reports from the Company's consultants are improper.

Q. On pages 41-42 of his direct testimony, Mr. Anderson testified generally about aquifer storage fields, and he then testified (pages 43-48) specifically about operations at Manlove Field. Please describe the physical characteristics of Manlove Field.

A. At Manlove Field, natural gas is stored in the Mt. Simon sandstone formation at a depth of approximately 4,000 feet. The Mt. Simon is an aquifer and originally contained no gas or oil. The geology of this sandstone is very complex and non-homogeneous.

Q. You and Mr. Wear, in his rebuttal testimony, as well as Mr. Anderson, refer to Manlove Field as an aquifer field. Please explain what an aquifer field is and what distinguishes an aquifer field from other types of natural gas storage fields.

A. Aquifers are porous and permeable rock formations. The pores are saturated with water under pressure. To store gas, the native water must be displaced by injecting gas at a pressure higher than the original aquifer pressure. In addition to aquifers, gas is also stored underground in depleted oil and gas reservoirs, pinnacle reefs, and salt caverns.

Gas storage in an aquifer is inherently less efficient than any of the other types of storage. This puts a premium on the proper management of aquifer storage fields. Injecting gas in and withdrawing gas from an aquifer results in large proportions of the injected gas being trapped in the pores by the water. This is not normally true in depleted oil and gas reservoirs where the small amounts of water present are usually immobile. Large quantities of water are usually produced along with the gas in aquifer storage. Understanding and managing water production in an aquifer is vital to maximizing the usefulness of the aquifer.

The working volumes of other types of storage are usually fixed or more readily controlled. In aquifer storage, the working volume is dependent on gas inventory, aquifer strength, and operational practices.

Q. You stated that the geology of the Mt. Simon sandstone is complex and non-homogeneous. What does this mean and how does it affect operation of the field?

A. The Mt. Simon sandstone at Manlove Field and the associated aquifer is a difficult reservoir system to describe and predict. The complex, non-homogenous nature of the field is a result of the environment during which the reservoir sand was deposited. It is believed that the Mt. Simon sand was deposited at Manlove Field hundreds of millions of years ago in an environment that resulted in many tortuous disconnected channels in the sandstone that exists today. This is evident by the difficulty in attempting to correlate zones in adjacent wells let alone across wide portions of the reservoir. The entire Mt. Simon gas storage zone is composed of multiple layers or strata. There are large permeability variations within layers (horizontally) and between layers (vertically). Gas and water move more rapidly through the most permeable layers. As a result, the horizontal and vertical distributions of gas are not uniform. There are large volumes of rock within the reservoir storage area that contain little or no gas. The depth of the gas storage zone varies significantly across the field.

Because permeability varies greatly, well injectivity and productivity vary greatly. The non-uniform gas distribution results in large variations in water production from well to well. The distribution and continuity of permeability cannot be readily described in the field area. Consequently, the path of gas movement cannot be accurately predicted. Attempting to resolve this in reservoir models is most difficult. One effect of the complex, non-homogeneous nature is greater uncertainty of reservoir simulation forecasts. Because of the uncertainty of the simulation forecasts, the results of reservoir studies should be considered specific to the conditions for which they were run and caution should be used when attempting to extrapolate beyond those conditions.

Q. Please describe how the Company typically operates Manlove Field.

A. Manlove Field is typically operated in the following manner. At the start of each injection season, a working gas target for the injection season is established. Factors that determine the working gas target are the prior injection season's working gas total, the prior withdrawal season's total, and the anticipated increase, if any, in working gas. Once the working gas target is established, an injection schedule is made showing targeted injection volumes for each month and average daily rates for each month. A maximum of approximately 280 MDth per day can be injected until the compressor discharge pressure reaches approximately 1,750 psig whereupon the maximum injection rate will begin to decline.

As the injection season progresses, actual injection volumes are compared to the schedule. Monthly totals and the seasonal cumulative total is monitored. If a particular month is long or short compared to the schedule or if the working gas target is revised, the remainder of the injection schedule is adjusted accordingly. For scheduling purposes an end-date for injection is somewhat arbitrarily selected using historical information. As the actual end of injection approaches, the final end-date is determined considering any revisions to the working gas target, weather, and other gas supply issues, such as leased storage inventories and actual daily deliveries of customer-owned gas.

Before withdrawal begins, a withdrawal plan is developed for the season showing monthly targeted withdrawal volumes and average daily withdrawal volumes for each month. A decline curve is developed showing the cumulative withdrawal quantity at which field peaking begins to decline from its maximum of 800 MDth per day. The decline curve is constructed considering field performance from the previous year and any changes in working gas volumes. Generally, an initial minimum daily withdrawal rate is specified to ensure that approximately 6 MMDth is withdrawn in the first two and one-half weeks of the season. The purpose is to reverse the outward pressure gradient and the expansion of the gas as rapidly and as completely as practical in order to help minimize the trapping of gas at the field perimeter.

As the withdrawal season progresses, monthly targets are adjusted. Weather is a primary driver of variations from the schedule. The end-date of withdrawal is determined based on the seasonal target, weather, and other gas supply issues, such as leased storage inventories and actual deliveries of customer-owned gas. A major objective of the storage operation is to fully cycle the working gas volumes each year.

Q. What is the typical injection season for Manlove Field?

A. The injection season typically begins in the first or second week of March and ends in the first or second week of December.

Q. What is the typical withdrawal season for Manlove Field?

A. The withdrawal season typically begins in the first or second week of December and ends in the first or second week of March.

Q. Did operations in fiscal year 2001 conform to your description of typical operations?

A. No. In fiscal year 2001, withdrawal began approximately two weeks early on November 21, 2000. Mr. Wear, in his rebuttal testimony, cites the reason for this early onset of withdrawal. Other than this event, storage operations for fiscal year 2001 conformed to that of a typical year.

Q. On pages 45-48 of his direct testimony, Mr. Anderson testified about the increase in working gas at Manlove Field. Are there any benefits to Manlove Field from cycling more than 27 Bscf per season?

A. The Company has realized tangible benefits from cycling more than 27 Bscf per season. These benefits are an extension in the field decline point, improved field performance as measured by end-of-season water-gas ratios and less gas becoming trapped as compared to the top gas volume.

Q. When you refer to "gas becoming trapped" are you using that terminology in the same context as Mr. Anderson when, on page 55 of his direct testimony, he defines "Trapped Gas" as non-recoverable base gas?

A. No, I am referring to the trapping of gas in a generic sense and am not referring to any specific accounting category of gas inventory.

Q. Please describe the field decline point extension benefit.

A. Prior to the increase from approximately 27 Bscf of working gas to approximately 35 Bscf of working gas, the field reached the point at which peaking performance began to decline at a cumulative withdrawal volume of approximately 18 Bscf. Now that 35 Bscf is available, that decline point has been extended to approximately 27 Bscf. This means that the Company has an extended period of access to Manlove Field's full, undiminished peaking capability.

Consider two scenarios. Assume that third parties are purchasing services (what Mr. Wear calls hub services) under which they will have a cumulative inventory of 8 Bscf. The examples consider both the Company's and North Shore Gas Company's ("North Shore") combined use of Manlove Field, that is, approximately 27 Bscf per season. First, a peak requirement occurs after all third-parties have withdrawn all of their 8 Bscf, and second, a peak requirement occurs before third parties have withdrawn all of their 8 Bscf. Under the first scenario, the Company has access to the full peaking capability of Manlove Field until the Company and North Shore have withdrawn 19 Bscf (27 Bscf – 8 Bscf). This is 1 Bscf greater than if no third party gas had been stored. Under the second scenario, the Company has access to the full peaking capability of Manlove Field until the Company and North Shore have withdrawn 19 Bscf *plus* whatever volume of third party gas remains in the field. In either scenario, the Company has the benefit of extended access to full peaking capability from the presence of the third party gas.

Q. Please describe why you believe field performance has improved.

A. The Company can measure improved performance through end of season cumulative water-gas ratios. The water-gas ratio (WGR) is the ratio of total seasonal withdrawn water to total seasonal withdrawn gas, with the water expressed in barrels and the gas in millions of standard cubic feet (bbl/MMscf). The significance of water-gas ratios as a measure of field performance is at least twofold:

1. Low WGRs indicate higher gas saturations and more efficient use of the storage space.
2. As wells die or become non-productive gas pressure is no longer sufficient to lift water from the wellbore. The production of water wastes reservoir energy. The less water produced, as measured by a lower WGR, the lower the pressure required to remove the water and the longer a well can produce.

Q. You attributed this improvement to increased injection volumes. Why were increased injection volumes key to the improved performance?

A. The improved field performance is directly related to higher gas saturations in the central field area. These higher gas saturations in the central field area are due in large part to the increased injection volumes.

Q. Please explain the benefit resulting from less gas becoming trapped.

A. The increase in the working gas volume of Manlove Field by 8 Bscf has been a contributing factor to the reduction in the percentage of gas that becomes trapped. Typical estimates of the amount of gas that would become trapped, as shown in numerous reports by the Company's consultants prior to the addition of third-party gas, was 5 to 6 percent or approximately 1.5 Bscf per year on a working gas volume of 27 Bscf. Actual allocation of maintenance gas following the increase in working gas has been 2 percent or approximately 0.7 Bscf per year on a working gas volume of 35 Bscf -- about one-half the predicted amount. The improved field performance, evidenced by extended peaking and low water-gas ratios, indicates the current maintenance gas allocation is realistic and clearly demonstrates that the increased working gas volume has been accompanied by a decreased amount of gas becoming trapped. This is consistent with higher gas saturations in the central field area.

Q. Do you agree with Mr. Anderson where he cites a report by Smedvig Technologies dated April 9, 1998, and draws the conclusion that the field would be adversely affected if the Company was unable to successfully market the 8 Bscf of third-party storage services?

A. No. The simulations that were run for the Smedvig study do not reflect the actual circumstances under which the Company operates with third party storage. It would certainly be problematic if the Company were to inject 35 Bscf to meet its system requirements and subsequently withdraw only 27 Bscf. This would inevitably tend to increase the amount of gas that would become trapped throughout the field and lost beyond the perimeter wells. However, the Smedvig study does not take into account the mix of hub transactions with the use of the field to meet system requirements.

The Smedvig study simulated two years of withdrawal of 30.5 Bscf followed by a third year of withdrawal at varying lesser amounts and a fourth year with withdrawal again at 30.5 Bscf. During each run, it was assumed that the third year's drop in withdrawal volume was unexpected; the larger volume was simulated to be injected but not subsequently withdrawn. While this scenario accurately represents what may occur due to the unpredictability of weather, it does not accurately represent what would occur if the Company were not successful in marketing available storage to third parties as Mr. Anderson opined. If the Company were to be unsuccessful in marketing the available storage, this would be known well before the injection season was complete and injection schedules would be adjusted to accommodate a lower working gas target.

Q. What is the proper conclusion of the Smedvig study?

A. That it is detrimental to proceed to inject gas throughout an injection season to reach a rigidly determined working gas target and then to unexpectedly withdraw significantly less than that target. The field should be managed in a manner that minimizes the possibility of this occurrence.

Q. Were any studies performed to model a more realistic scenario inclusive of hub services?

A. Yes. The Company has a study performed by Roxar dated July 1999, titled, "Effect of Increasing Seasonal Stored Gas Volume on Reservoir Performance at Manlove Field." The Company provided this study in response to a Staff data request. The study simulated field performance over 8 consecutive years. Withdrawals for years 1, 2, and 3, were 30.5 Bscf, 33.8 Bscf, and 33.8 Bscf, respectively, for each of 8 cases. Case 1 simulated withdrawals at a constant 33.8 Bscf/year for years 4 thru 8 and Case 2 simulated withdrawals at a constant 27 Bscf/year for years 4 thru 8. Cases 3 through 8 simulated withdrawals of either 27 Bscf/year or 33.8 Bscf/year for years 4 through 8, alternating in different patterns for each case.

Q. Did the study indicate that the performance of Manlove Field would be harmed by varying the cycled quantities?

A. No.

Q. Is there another reason why the Roxar study from 1999 is more applicable than the Smedvig study from 1998?

A. Yes. The forecast period of the Smedvig study was only four years. By contrast the Roxar study simulated eight years. This is particularly important because of the condition of the reservoir at the starting date of the simulation forecasts. Both studies began with the reservoir model data updated through the 1995-96 withdrawal period. The period of Manlove Field's history leading up to 1996 was marked by a significant decline in reservoir performance; water-gas ratios increased from about 60 bbl/MMscf in 1990 to just over 100 bbl/MMscf in 1996. The influence of the relatively poor state of the reservoir would have adversely affected the first several years of the forecast, encompassing perhaps the entire length of the Smedvig study, and would have tended to increase any estimate of gas lost by that volume required to restore reservoir performance. This indicates that the Smedvig study may simply not have been long enough to be applicable and underscores the need to consider the parameters under which studies are run before drawing conclusions from them.

Q. If increased working inventories and increased cycling is beneficial to Manlove storage operations, then why not allocate all of the 35 Bscf seasonal capability to system supply and leave none to hub services?

A. Because of the limited withdrawal period of Manlove Field, during a warmer than normal winter period there is a high probability that the major objective of cycling 35 Bscf of system supply would not be met. This could lead to increased volumes of gas being trapped or lost as previously stated. The predicament is relieved by the nature of Hub transactions that obligate the customer to inject and withdraw like quantities. The net result is that the Company realizes the benefits of the additional storage volumes while minimizing the risks.

Q. On page 58 of his testimony, Mr. Anderson cites a Company memorandum dated September 15, 1997, and a report dated June 30, 1997. He uses the estimated cushion gas requirement of 6.5 - 7.5 percent of the cycled volume from the report to conclude that an increase in working gas of 8 Bscf would result in a 0.52 - 0.60 Bscf of gas loss at a cost of $3.2 - $3.7 million dollars. Do you agree with his conclusion?

A. No. As Staff has noted, beginning in 1999, the Company began to allocate 2 percent of injected volumes to maintenance gas. The fact that field performance has not declined is clear evidence that a 6.5 – 7.5 percent allocation is not proper, and, consequently, Mr. Anderson's estimated gas loss and associated costs are overstated.

Q. On pages 46 and 58 of his testimony, Mr. Anderson notes that in a Company report dated June 30, 1997, the term "cushion gas" is used instead of the term "maintenance gas". On page 57, he similarly notes that the April 9, 1998, Smedvig study references annual cushion gas injections. Should any significance be attached to the use of these terms instead of the term maintenance gas?

A. None at all. The Company had not adopted the use of the term maintenance gas prior to 1999. Furthermore, the authors of those reports were engineers, not accountants, and in that context I would consider the terms to be synonyms.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.